BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2018-319-E

IN THE MATTER OF:	)	
	)	
Application of Duke Energy Carolinas, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order	)))	**DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF VOTE SOLAR**
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes, 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years beginning in August 2007, where I worked as a Policy Analyst and then Senior Policy Analyst on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and efficiency policy.

I left N.C. State University in 2013 to join EQ Research as a Senior Policy Analyst, and later became a Project Manager and then Director. In my current position I coordinate EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry legislative, regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests. Outside of South Carolina, I have testified before the Colorado Public Utilities Commission, the New Hampshire Public Utilities Commission, the New Orleans City Council, the North Carolina Utilities

Commission, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, and the Utah Public Service Commission as an expert in distributed generation ("DG") policy, rate design, and cost of service.[1] My *curriculum vitae* is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE SOUTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony on behalf of The Alliance for Solar Choice in Commission Docket No. 2014-246-E addressing the implementation of 2014 Public Act 236, and in Docket Nos. 2015-53-E, 2015-54-E, and 2015-55-E addressing the applications of the state's three investor-owned utilities ("IOUs") to establish distributed energy resource programs pursuant to Public Act 246.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Vote Solar.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the rates application put forth by Duke Energy Carolinas ("DEC" or "the Company") on issues related to the Company's proposals involving residential basic facilities charges, AMI-enabled rate design, the South Carolina Grid Improvement Plan, and Excess Deferred Income Tax Rider EDIT-1. My testimony on all of these topics relates to cost of service and rate design. The purpose of my testimony is to show that:

[1] The New Orleans City Council regulates Entergy New Orleans in a manner similar to a state regulatory commission.

1. The Company's proposed increase in the residential basic facilities charge, which if approved would be the highest residential customer charge in the country among IOUs, is based on a fatally flawed methodology, veers away from traditional principles of rate design, and wholly ignores prior Commission precedent rejecting the use of the Minimum System Method for distribution cost classification.
2. The proposed residential basic facilities charge would disproportionately increase the rates of low-usage customers and reduce the ability of customers to adopt solar energy and energy efficiency to manage their electric bills.
3. The Company's plan for deploying AMI-enabled rate designs and, consequently, allowing customers to realize the full benefits of AMI, lacks the specificity and detail necessary to inform the Commission of whether the Company's actions will result in just and reasonable rates.
4. The Company's proposed rate design for recovery of costs associated with its Grid Improvement Plan, to the extent the Commission permits it to move forward, inappropriately classifies costs and over-assigns revenue responsibility to the residential class, without consideration of whether residential customers would see equivalent benefits from Grid Improvement Plan investments.
5. The volumetric rate design that the Company proposes for the Excess Deferred Income Tax Rider EDIT-1 is unreasonable and should be revised

to a percentage of bill-based design if the rider is approved in order to align it with the underlying causes of excess deferred income taxes.

6. Residential net metering customers provide an estimated benefit, in addition to any value of solar calculation, of over $1 million per year to the residential class by reducing the allocation of peak-driven costs to the class.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE RESIDENTIAL BASIC FACILITIES CHARGE.

A. My recommendations for setting the basic facilities charge are as follows:

1. The Commission should reject the changes the Company has made to its cost of service study and re-affirm precedent by directing the Company to eliminate the use of the Minimum System Method from its cost of service study.
2. The Commission should make a determination that the basic customer method, which defines customer-related costs as those directly attributable to a customer's service connection, metering, billing, and customer service, is the appropriate method for classifying customer-related costs.
3. The Commission should reject the Company's proposed residential basic facilities charge and instead limit any increase in the charge to the percentage increase in residential class revenue requirement that is ultimately adopted in this proceeding.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON AMI-ENABLED RATES, THE GRID MODERNIZATION PLAN, AND RIDER EDIT-1.

A. My recommendations on these topics are as follows:

1. AMI-Enabled Rate Design: The Commission should direct DEC to proceed with rate pilots and planning in a manner that is fully aligned with the directives placed on DEC in North Carolina, including but not limited to filing two pilot rate proposals, one for residential customers and one for small non-residential customers, and a complete rate design plan with the Commission within 60 days of a decision in this proceeding.
2. Grid Modernization Plan: The Commission should take several actions to ensure that the costs and benefits of the Company's Grid Improvement Plan are distributed equitably and that cost recovery is consistent with cost causation:
   a. Make a finding that Grid Improvement Plan investments cannot be considered part of a standard minimum distribution system because by their very nature they are extraordinary in character, regardless of whether the Commission accepts the use of the Minimum System Method in the Company's cost of service study.
   b. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

c. Direct DEC to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align the allocation and recovery of costs with the results of the class-level cost-benefit evaluations and proper identification of energy and demand costs.

3. Rider EDIT-1: If the Commission approves Rider EDIT-1, the rate design should be revised to a percentage of bill-based mechanism in order to align it with the underlying causes of excess deferred income taxes.

II. DEC'S RESIDENTIAL BASIC FACILITIES CHARGE PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR INCREASES TO BASIC FACILITIES CHARGES.

A. The Company proposes to increase the basic facilities charge for customers taking service under Schedule RS and Schedule RE (electric heating) from the current amount of $8.29/month to $28.00/month. The increase proposed for Schedule RT, an optional residential time-varying rate with a demand charge component, is from $9.93/month to $27.08/month. Current and proposed basic facilities charges for all customer classes are show in Exhibit No. 6 of the Direct Testimony of DEC Witness Michael Pirro ("Pirro Direct"). The Company's derivation of basic facilities charges rests in large part on its use of the "Minimum System Method", which classifies a significant portion of the costs associated with the shared distribution system (*i.e.*, upstream from customer's connection to the grid) as customer-related and therefore includable within the basic facilities charge.

Q. DO THE COMPANY'S PROPOSALS CONTAIN ANY CONSIDERATION OF CUSTOMER IMPACTS OR ELEMENTS DESIGNED TO MITIGATE ADVERSE IMPACTS GENERALLY, OR ON CERTAIN TYPES OF CUSTOMERS?

A. No. The proposed residential basic facilities charges are derived from costs that DEC's cost of service study classifies as customer-related, without modification.

Q. IS THIS LACK OF CONSIDERATION OF CUSTOMER IMPACTS NORMAL IN YOUR EXPERIENCE?

A. It is highly unusual. Even utilities that generally believe that higher residential fixed charges are appropriate based on the use of methodologies similar to the Company's typically seek to moderate the impact by proposing charges at lower amounts than those derived from their cost studies. This is one aspect of the ratemaking concept generally known as "gradualism", which seeks to avoid abrupt changes that would have large adverse impacts on one or more groups of customers.

DEC is no stranger to this concept. For instance, in its most recent North Carolina general rate case DEC contended that its cost of service study supported a residential basic facilities charge of $23.78/month, but it only proposed an increase from $11.80/month to $17.79/month in order to "moderate any effect on low usage customers."[2] DEC further offered testimony in this case noting that when pursuing "cost justified" rates "it is important to consider the impact upon

[2] North Carolinas Utility Commission ("NCUC"). Docket No. E-7 Sub 1146. Direct Testimony of Michael Pirro, p. 13, lines 15-18. August 25, 2017. Available at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=dbff898e-22f1-4aa2-8322-96186a4e3987.

customers and to employ the principle of "gradualism"."[3] Therefore DEC proposed an increase in the residential basic facilities charge of 50% of the difference between the existing charge and the theoretical charge indicated in the Company's cost of service study.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY ON THE COMPANY'S PROPOSED RESIDENTIAL BASIC FACILITIES CHARGES IS ORGANIZED.

A. In Section II-A, I describe in more detail how the proposals are an extreme departure from sound ratemaking principles and how those principles have been put into practice in other states, as evidenced by how dramatically the proposed rates differ and the amount of the associated increases compare to national statistics. In Section II-B I describe the considerable flaws in the methodology the Company uses to arrive at its proposed basic facilities charges. Section II-C of my testimony contains an alternative calculation of customer-related costs based on eliminating those flaws.

A. The Company's Proposal Departs From Sound Ratemaking Practices

Q. PLEASE SUMMARIZE THE ELEMENTS OF GOOD RATEMAKING PRACTICE?

A. Good ratemaking is an exercise in balancing a suite of goals. The oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure, listing a set of eight principles

[3] *Id.* p. 11, lines 5-7.

to consider. I have paraphrased those principles that I believe are most relevant to this proceeding below:

1. The "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.
2. Effectiveness in yielding total revenue requirements under the fair return standard.
3. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers (*i.e.*, gradualism).
4. Fairness of the rates in apportioning the total cost of service among different consumers.
5. Avoidance of undue discrimination.
6. Efficiency of the rate classes and blocks in discouraging wasteful use of service (*i.e.*, economic efficiency).[4]

The principles themselves are generally non-controversial. However, it is generally recognized that they are sometimes in conflict with one another, hence the need to achieve a balance. Prevailing rate designs for residential customers on the national level are indicative of how that balance is achieved in practice.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL BASIC FACILITIES COMPARE TO THOSE APPROVED BY REGULATORS IN OTHER STATES?

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[4] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 291.

A. The proposed basic facilities charges for the residential class cannot be described as anything other than extreme. They would result in the *highest* fixed monthly charges placed on residential customers of any investor-owned utility ("IOU") in the country by a significant margin ($3.00/month higher than the current highest charge of $25.00/month). Furthermore, they would result in increases far in excess in both monetary and percentage terms, of increases approved by regulators in other states during rate cases filed during roughly the last four years, other Duke Energy affiliates, and those of corporations deemed comparable to Duke Energy as described in the Direct Testimony of Robert Hevert.[5]

Q. PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU CONDUCTED TO SUPPORT THIS CLAIM.

A. Table 1 below presents comparisons between current fixed monthly charge averages and DEC's current ($8.29/month) and proposed rates ($28.00/month). Table 2 presents averages of *increases* approved in rate cases filed during the last four years relative to the Company's proposed increase of $19.71/month, or 237.76%.

Table 1: Fixed Charge Comparisons

Basis of Comparison	Fixed Charge ($)	DEC Current Difference ($)	DEC Current Difference %	DEC Proposed Difference ($)	DEC Proposed Difference %
National Average	$10.42	-$2.13	-20.47%	$17.58	168.63%
DEC Affiliate Average	$10.32	-$2.03	-19.65%	$17.68	171.39%
DEC Comparables	$11.01	-$2.72	-24.68%	$16.99	154.38%
DEC Current	$8.29				
DEC Proposed	$28.00				

[5] Revised Direct Testimony of Robert B. Hevert ("Hevert Direct"), p. 17, Table 1.

Table 2: Fixed Charge Increase Comparisons

Basis of Comparison	Increase ($)	Increase (%)	DEC Above ($)	DEC Above (%)
National Average	$0.94	13.55%	$18.77	224.21%
DEC Affiliate Average	$2.83	45.65%	$16.88	192.10%
DEC Comparables	$1.02	15.41%	$18.69	222.35%
DEC Proposed	$19.71	237.76%		

Table 1 shows that DEC's current residential customer charge is only moderately below the national average and the average for Duke Energy affiliates. Alternatively, though not presented in Table 1, the median fixed charge among IOUs, at $9.50/month, is lower than the simple average. DEC's proposed charge of $28.00/month is even more extreme relative to the median than the average.

The increase DEC proposes would place the residential customer charge well in excess of the national average and as shown in Table 2, and would dramatically exceed recent national averages for fixed charge increases and those awarded to Duke Energy affiliates. As with current fixed charges themselves, the median national increases in monetary and percentage terms are lower than the averages, at $0.25/month and 2.9%. In monetary terms, DEC's proposed increase is *more than 20 times* the average monetary increase approved in recent years by regulators in other states. The percentage increase is *more than 17 times* the national average percentage increase.

The five increases for Duke Energy affiliates in Table 2 refer to:

- A $0/month (0%) increase granted to Duke Energy Ohio in 2018 resulting in a current rate of $6.00/month.
- A $6.50/month (144.4%) increase granted to Duke Energy Kentucky in 2018 resulting in a current rate of $11.00/month.

- A $2.56/month (39.4%) increase granted to Duke Energy Progress (SC) in 2016 resulting in a current rate of $9.06/month.
- A $2.20/month (18.6%) increase granted to Duke Energy Carolinas (NC) in 2018 resulting in a current rate of $14.00/month.
- A $2.87/month (25.8%) increase granted to Duke Energy Progress (NC) in 2018 that results in a current rate of $14.00/month.

Combined, these translate to the $2.83/month and 45.65% averages reflected in Table 2.

Q. WHAT RESEARCH DID YOU CONDUCT TO DEVELOP THE DATA UNDERLYING THESE RESULTS?

A. I conducted a review of current residential customer charges for 172 IOUs in 49 states and the District of Columbia.[6] The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus the survey presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 178 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets are current as of February 8, 2019.

[6] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

As I noted above, the "comparable" utilities are based on the proxy companies that DEC witness Hevert selected for his return on equity analysis. To generate these averages, I selected all of the local distribution utilities affiliated with these companies from my larger dataset of fixed charges and approved increases.

Q. WHY DID YOU INCLUDE A COMPARISON TO COMPANIES "COMPARABLE" TO DEC IN YOUR ANALYSIS?

A. DEC witness Hevert describes his selection of proxy companies as intended to consist of those with "risk profiles comparable to the subject company."[7] To be clear, none of his selection criteria involve an assessment of a company's risk profile based on revenue generated via fixed charges. However, it is inescapable that fixed charges do have the effect of providing a high degree of certainty for a portion of a utility's revenue during a given month or year (*i.e.*, little or no risk of under-recovery), making it less vulnerable to sales fluctuations.

I do not make any claims as to how fixed charge revenue may specifically affect a utility's risk profile. Nevertheless, I do believe that Mr. Hevert's list of proxy companies is illustrative insofar as it represents an additional basis for comparing different utilities, and shows results similar to the national and Duke Energy affiliate comparisons I have done. Certainly, the comparisons do not suggest that the Company's financial position presents a driving need for such a large increase in order to reduce its risk profile.

[7] Hevert Direct. p. 15, lines 11-12.

Q. SINCE YOU OBSERVE THAT GRADUALISM IS SOMEWHAT SUBJECTIVE, HOW DO YOU SUGGEST THE COMMISSION EVALUATE IT FOR THE PURPOSES OF SETTING THE BASIC FACILITIES CHARGE?

A. The national statistics I have presented on residential fixed charges and recent fixed charge increases are objective indicators of how gradualism is practiced for the purpose of setting residential fixed charges. Whether one considers the statistical means or medians the proper measure, the results are similar. Alternatively, gradualism is often practiced by relating fixed charge increases to the adopted percentage increase in class revenue. In this case, the Company's proposed residential class base revenue increase is roughly 17.5%[8] That percentage increase equates to a residential basic facilities customer charge of $9.74/month. Such an approach is also objective because it stems from hard numbers rather than subjective judgments.

Q. DOES THE COMPANY'S BASIC FACILITIES CHARGE ADHERE TO THE PRINCIPLE OF GRADUALISM?

A. No, even using a very loose definition of the term. Duke Energy affiliates have recently sought large fixed charge increases in other jurisdictions, but none as drastic as what DEC has proposed here. As I have previously described, in North Carolina the Company reduced the amount of the proposed increase in the basic facilities charge by 50% relative to the amount indicated by its cost of service study. While I disagree that the basis for the "cost justified" rate in its North

[8] Based on Pirro Direct, Exhibit No. 4 excluding riders.

Carolina cost of service study was accurate (as I do in the instant proceeding) or that the North Carolina proposal reflected a reasonable adherence to gradualism, the North Carolina proposal was at least somewhat more consistent with the principle.

In fact, the Company's basic facilities proposal in this proceeding is even more extreme than it appears at first glance. I say this because for the purpose of establishing total class revenue requirements, the Company uses a rate impact mitigation formula shown in Pirro Exhibit No. 4 as the "reduction in variance from the average". Thus for the purpose of determining class revenue requirements, the Company seeks to reduce how much class returns depart from the system average, but does not attempt to create full unity in terms of class rate of return at proposed rates. This reduces the overall residential class revenue requirement from what is indicated by the Company's cost of service study. However, the Company does not propose to make an equivalent downward adjustment in the proposed basic facilities charges, making the basic facilities charge an even larger component of overall rates than it would otherwise be.

Q. WHY SHOULD CUSTOMER PREFERENCES BE CONSIDERED IN RATE DESIGN?

A. Customer preferences are an element of public acceptability. Inherent in utility regulation is the idea that regulation should function as a substitute for competition. Since customers cannot select their electric distribution provider based on service characteristics or prices, regulation is critical for protecting them from being sold goods that they do not want or need at a given price point. Or, the corollary, to provide them with the services they do desire at a cost less than or equal to the value of the good. This concept has been referred to as using regulation to impose the "disciplines of competitive markets".[9]

There are broader consequences to this idea, involving the costs and benefits of utility investments and how they are distributed among customers, but it is also central to rate design. Since customers cannot make their preferences known by shopping around, those preferences must be discerned through other means, such as studies or rate pilots. Customer preferences fall within Bonbright's "practical attributes", and should be balanced with the other ratemaking goals such as economic efficiency, rate stability, and fairness at apportioning cost of service. Ideally, in replicating the function of a competitive market, a customer would have a suite of potential options to choose from that maintain this balance but also respond to their individual preferences.

Q. HAS THE COMPANY CONDUCTED ANY STUDIES OF CUSTOMER PREFERENCES REGARDING FIXED CHARGES?

A. DEC has participated in an Electric Power Research Institute ("EPRI") study to consider residential rate design choices. The Company has indicated that the study addresses fixed charges.[10] However, I have not been able to view the report because it is not publicly accessible, requiring a download fee of $25,000.[11]

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[9] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 17, REGULATORY ASSISTANCE PROJECT (2000), available at http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.
[10] DEC response to VS 4-3, attached in Exhibit JRB-2, p.14.
[11] See the EPRI website at: https://www.epri.com/#/pages/product/000000003002013359/?lang=en-US.

Q. WOULD IT BE REASONABLE FOR THE RESULTS OF THIS STUDY TO BE CONSIDERED IN THIS PROCEEDING?

A. Yes, and I say this without knowing the findings of the study. I leave how that could or should occur to the Commission to decide. That said, I find it troubling that the Company possesses information that appears likely to be highly relevant to one of the most, if not the most, significant aspects of its application, which it cannot or will not make available to other parties.

Q. HOW WOULD THE COMPANY'S RESIDENTIAL BASIC FACILITIES CHARGE PROPOSALS AFFECT CUSTOMER BILLS?

A. Customers with relatively high usage would be advantaged, experiencing a lower overall rate increase or even a decrease for the highest using customers. Lower usage customers would be disadvantaged, experiencing rate increases well in excess of the average rate increase. For instance, the Company's collective rates proposals would cause a bill increase of $17.23/month (27.3%) for a customer on Schedule RS with average usage of 500 kWh per month. By contrast, a customer using 2,000 kWh per month would only experience a $9.75 (4.21%) monthly increase. Table 3 shows the breakdown of bill impacts for Schedule RS.[12]

[12] Sourced from Pirro Direct, Exhibit No. 3, with "Amount of Increase" added as a new column.

Table 3: Schedule RS Rate Impacts at Different Usage Levels

Monthly kWh	Present Schedule Revenue	Proposed Schedule Revenue	Amount of Increase	Percent Increase
0	$9.18	$28.89	$19.71	214.71%
100	$19.96	$39.18	$19.21	96.24%
250	$36.14	$54.61	$18.47	51.10%
500	$63.10	$80.33	$17.23	27.30%
750	$90.06	$106.05	$15.98	17.75%
1,000	$117.02	$131.76	$14.74	12.60%
2,000	$231.40	$241.16	$9.75	4.21%
3,000	$345.79	$350.55	$4.76	1.38%
4,000	$460.17	$459.94	-$0.23	-0.05%
5,000	$574.55	$569.33	-$5.22	-0.91%
6,000	$688.93	$678.72	-$10.21	-1.48%

The impacts would be similar though not identical for customers on Schedule RE because they use more electricity on average than Schedule RS customers.

Q. WHAT TYPES OF CUSTOMERS WOULD BE MOST ADVERSELY IMPACTED BY THE LARGE INCREASE IN THE FIXED CHARGE?

A. Starting at the highest level, the majority of customers on Schedule RS are made worse off by fixed charge rates as opposed to volumetric ($/kWh) rates. A residential customer is indifferent to fixed versus volumetric charges at a monthly average use of roughly 1,050 kWh. In other words, if a fixed charge was translated to a volumetric charge that raises the same amount of revenue, a residential customer using 1,050 kWh per month would pay approximately the same amount as they would if the charge remained a fixed monthly amount. Customers using more than this indifference amount are better off with higher fixed charges, while those using lesser amounts are worse off. Roughly 53% of customers on Schedule RS use less than 1,000 kWh per month so the majority of that class is made worse off.[13] The farther a customer is from this indifference point in terms of average usage, the greater the impacts are, so lowest usage customers are the most adversely affected and the highest use customers stand to benefit the most.

Net-metered customers on Schedule RS would be more adversely affected than the RS class as a whole because 66.8% of these customers average less than 1,000 kWh of monthly usage.[14] One would also expect customers with smaller homes, fewer or smaller devices and appliances, and non-electric heating to be made worse off because these customers would generally use less electricity. Customers on Schedule RE, reserved for those with electric space and water heating, are generally made better off. It is not precisely clear how the rate impacts would vary by income level because the Company has not performed such an analysis.[15]

However, the Company has provided information indicating that households with annual incomes of $30,000 or less have average usage of 913 kWh/month.[16] This suggests that customers in this income category are generally made worse off by fixed charges relative to volumetric charges since this average usage falls below the indifference threshold. It is only suggestive though, because

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[13] DEC response to VS 1-7, attached in Exhibit JRB-2, p. 4.
[14] *Id.*
[15] DEC response to VS 1-12(a), attached in Exhibit JRB-2, p.8.
[16] DEC response to VS 5-1(a), attached in Exhibit JRB-2, p.18.

average usage does not indicate the percentage of customers in this income category that fall below or above the indifference threshold.

Q. **IS THIS RESULT CONSISTENT WITH THE PRINCIPLES OF FAIR APPORTIONMENT OF COST OF SERVICE AND ECONOMIC EFFICIENCY?**

A. No. It causes lower usage customers to subsidize higher usage customers and encourages wasteful use of service. The underlying causes of this outcome are the flaws in the Minimum System Method, which reflects a significant amount of demand-related costs as customer-related. In doing so, it eliminates the price signal that would otherwise be present in rates for the costs of that demand. A zero-load customer adds no demand to the system and therefore does not cause any additional costs beyond those required for grid connection. In other words, that customer does not impose any additional costs on the shared distribution system. That customer does not take up any "space" on the system that could otherwise be used to serve other customers. Yet that customer would still be required to pay for a considerable amount of demand-related costs through the Company's proposed basic facilities charge. I discuss this flaw in the Minimum System Method in more detail in Section II-B.

Q. **WHAT ARE THE RESULTS OF RATES THAT FAIL TO ENCOURAGE ECONOMICALLY EFFICIENT CUSTOMER BEHAVIOR?**

A. It dampens consumer incentives to save electricity, either through behavioral changes or investments in energy-efficient equipment and on-site generation such as solar. That in turn compels additional utility spending to meet those increased needs in the form of future generation, transmission, or distribution investments. This adds risk to the system since some future costs may not be possible to know with certainty (e.g., natural gas prices, coal ash remediation), whereas the present costs of demand-side investments can be known.

Fixed charges also directly increase the costs of demand-side programs that provide incentives for energy efficient equipment. By reducing customer savings potential, the incentive necessary to encourage the same amount of investment and achieve the same goals must be larger than it would otherwise be. At the maximum basic facilities charge I propose in the following section of my testimony ($11.64/month), the energy rate would have to be 1.55 cents/kWh higher to generate the same amount of revenue. A consumer replacing a conventional air-source heat pump with an Energy Star rated model would save roughly $44 less per year and more than $870 over a 20-year system lifetime under Company's proposed basic facilities charge relative my recommended charge.[17]

The foregone savings for even a moderately-sized on-site solar system would be much larger. A five-kilowatt ("kW") residential solar system could be expected to produce roughly 6,300 kWh annually in DEC's South Carolina territory.[18] Based on this, the foregone savings would be roughly $98 annually

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[17] Based on default values in the Federal Energy Management Program's Energy- and Cost-savings Calculator for Energy-Efficient Products, *available at*: https://www.energy.gov/eere/femp/energy-and-cost-savings-calculators-energy-efficient-products

[18] Based on PVWatts outputs, for Greenville, South Carolina, *available at*: https://pvwatts.nrel.gov/index.php. Estimate accounts for energy output degradation at 1% annually.

and more than $1,950 over a 20-year system lifetime. These impacts are sufficient to make material impacts on consumer investment decisions.

B. The Validity of the Minimum System Method

Q. HOW DOES THE COMPANY ARRIVE AT THE PROPOSED BASIC FACILITIES CHARGES?

A. The charges are based on the customer unit costs derived from the Company's embedded cost of service study. They represent the monthly payment that would be required to raise the revenue associated with costs that the cost of service study has classified as customer-related (*i.e.*, revenue divided by customer-months). Customer-related costs refer to those that vary in relation to the number of customers the utility serves, composed of costs associated with metering, billing, customer service, and customer service drops.

To these costs the Company's cost of service study adds allocations for more generalized administrative and general costs and classifies a significant portion of the shared distribution system that exists beyond the customer connection to the grid as customer-related. These shared distribution costs are composed of line transformers (FERC Account 368), secondary and primary overhead distribution lines (FERC Account 365), secondary and primary distribution lines (FERC Account 367), underground conduit (FERC Account 366) and secondary and primary distribution poles (FERC Account 364). I refer to these as the "shared" distribution system because unlike equipment such as meters or a customer's service drop, the shared components serve the system as a whole rather than individual customers.

The portion of the shared system that the Company classifies as customer-related, as opposed to demand-related, is derived using the so-called Minimum System Method. The Minimum System Method is based on the premise that a portion of the shared distribution system is related to providing a customer with the ability to take electric service. In other words, it assumes that a certain number of poles and miles of wire are necessary to provide electric service even if a customer had only a minimal demand.

Q. HAS THE MINIMUM SYSTEM METHOD HISTORICALLY BEEN USED IN DEC'S SOUTH CAROLINA SERVICE TERRITORY?

A. No. In 1991 on the recommendation of staff, Commission eliminated the use of the Minimum System Method from the Company's South Carolina cost of service study in favor of using a "more appropriate allocation factor."[19]

Q. DO YOU AGREE THAT THE MINIMUM SYSTEM METHOD IS A VALID METHOD OF CLASSIFYING DISTRIBUTION SYSTEM COSTS AND DEVELOPING BASIC FACILITIES CHARGES?

A. No. It is not valid for either cost allocation or rate design, though more generally the distinction between cost allocation and rate design is one that should be appreciated. Rate design does not always have to, nor should it, replicate cost allocation. It is sometimes appropriate to allocate certain costs in one way, but use

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[19] South Carolina Public Service Commission. Docket No. 91-216-E. Order No. 91-1022. p. 7. November 18, 1991.

rate designs that reflect consideration of other factors of cost causation. The Minimum System Method suffers from considerable flaws that make it unsuitable for either purpose. It should be discarded entirely in favor of more reliable and accurate methods of determining cost causation and responsibility.

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM METHOD AND HOW IT AFFECTS RATEMAKING.

A. As I previously noted, the theory behind the Minimum System Method is that the distribution system is designed to not only serve customer demand, but also to connect customers regardless of their need for electricity. That is, it assumes that some costs of the shared distribution system are incurred solely for the purpose of connecting each customer. It generally relies on an examination of the book costs associated with each cost category (*e.g.*, poles and towers) to establish the costs associated with a hypothetical distribution system that serves some minimal amount of customer load.

In ratemaking, the results of a minimum system analysis influence how distribution costs are allocated between rate classes. This is because the allocators based on the number of customers in a class differ from those based on demand. Generally speaking, the result of more costs being classified as customer-related is a higher revenue requirement for classes with the largest number of customers (*e.g.*, the residential class). In practice, it also has a cascading effect because other cost allocators rely in part on the distribution-related allocators. Most directly, it causes a larger share of distribution system operation and maintenance ("O&M")

expenses to be classified as customer-related in line with the percentage of distribution plant that is classified as customer-related.

More indirectly, allocating more of the revenue requirement or more distribution plant to the residential class causes dynamic allocators based on net plant or share of class revenue to also increase. Finally, it may also influence how revenue is collected in the form of customer, demand, or energy charges to the extent that charges are based on the classification of costs (*i.e.*, customer costs collected via customer or basic facilities charges).

Q. HOW DOES THE COMPANY JUSTIFY THE CLASSIFICATION OF SOME PORTIONS OF THE SHARED DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A. Company Witness Hager relies on the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Allocation Manual ("Cost Allocation Manual"), which in her words "states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related."[20] Having read through the NARUC Cost Allocation Manual in detail on multiple occasions I can say that this statement mischaracterizes its purpose and its contents in several key ways. I will point to specific examples showing the inaccuracy of this statement later in my testimony.

[20] Direct Testimony of Janice Hager ("Hager Direct"). p. 13, lines 4-6.

Q. DOES THE MINIMUM SYSTEM TRULY REPRESENT A ZERO-LOAD SYSTEM?

A. No. Company Witness Hager states that the Company's minimum system study is based on the infrastructure required to connect a customer with a *de minimus* load, like a light bulb.[21] However, in response to an information request, DEC stated that the analysis is based on the smallest equipment that the Company customarily installs.[22]

There is a large amount of daylight between what the Company typically installs versus what would actually be the smallest size equipment it would install if all customers had *de minimus* lighting loads. In fact, for each category of equipment the Company actually has smaller-sized equipment on its system than what it chose for its minimum system analysis. That equipment is currently contributing to serving full customer loads. Thus not only is the Company's analysis not based on the smallest equipment necessary to meet a minimal load, it has more load carrying capability than some portions of the existing utility system that are serving the full demands of some customers.

In practice, it is not possible to accurately assess what a truly "minimum system" would look like because such a system would be so dramatically different from the current utility system and how customers use it. The departure from reality extends to all levels of the system. For instance, in a near zero-load system customer service drops would have smaller load carrying capacity and customer

[21] Hager Direct, p. 14, line 19.

[22] DEC response to VS 1-2(a), attached in Exhibit JRB-2, p.2.

purchases of electricity would be so small that metering, billing, and customer service could be substantially simplified and less costly. Even meters themselves might be unnecessary from a cost-effectiveness standpoint, and it stands to reason that a near zero-load system would substantially affect the character of the transmission and generation system. Ultimately, the specification of a minimum system is a highly subjective departure from the reality of the system and how customers use electric service, and which is made increasingly anachronistic by growing customer loads and technological advances.

Q. PLEASE EXPLAIN HOW THE CONCEPTUAL FRAMEWORK OF THE MINIMUM SYSTEM METHOD IS ANACHRONISTIC.

A. In the early stages of electrification the concept of a minimum distribution system would have at least been closer to the reality of the system because electricity users were more dispersed and their electric loads were lower. That is, at some point in the past people desired to be connected to the electric grid to light a small number of light bulbs and perhaps sere a small electric appliance. Over time though, as electricity loads grow, the "single light bulb" scenario departs further and further from the reality of how customers use energy and why they desire to be connected to the grid. The fact is that the equipment that a utility customarily installs now to provide electric service is substantially larger and capable of serving more load than what it would have installed decades ago. Furthermore, with recent technological advances in the arena of distributed generation, modern society would never choose to build a minimum distribution system because it would be more costly to do so than other options of providing equivalent electric service.

Q. PLEASE ELABORATE ON YOUR CONTENTON THAT MODERN SOCIETY WOULD NEVER CHOOSE TO BUILD A MINIMUM ELECTRIC SYSTEM.

A. In the modern day, if a person only desired electric service capable of lighting a single light bulb they would not need a connection to the grid at all. A small self-generation system composed of a solar panel and a small battery would be sufficient to meet these needs at a lower cost than connecting to the grid. Alternatively, customers might take service from small localized and isolated grids rather than an interconnected system of distribution, transmission, and centralized generation. Of course, a large grid exodus has not occurred because customers do not desire a minimum system, they desire a system that can meet their full electricity needs. Additional load beyond a bare minimum makes grid isolation far more challenging for a customer from both a practical and economic standpoint. The considerable complications of reliably serving their full demand at all times are what compel customers to connect to the grid in the first place.

I have performed a high-level analysis of the cost of providing electricity to a single light bulb from a grid isolated distributed generation ("DG") system. For the purposes of this analysis I assumed that the light bulb is a 17-Watt LED bulb, the modern equivalent of a 100-Watt incandescent light bulb. The power system is composed of a 300-Watt solar panel, a 100 Amp-hour deep cycle battery, and a charge controller. All of these items are available off the shelf at a local home improvement store. The total cost of such a system would be roughly $700, including $100 in miscellaneous costs apart from the solar panel, battery, and charge controller. In reality, in this hypothetical scenario the battery and solar panel are oversized relative to the reasonable need because even if one used the light consistently for 10 hours a day every day, a fully charged battery would store enough electricity for nearly nine days of lighting and an average day of solar production, even in the month of December, would be sufficient to provide more than four full days of lighting electricity.

At a total cost of $700, the monthly cost would be $5.86/month if the system lasted 10 years or $11.72/month if it had only a five-year lifetime.[23] It would fully pay for itself relative to the Company's proposed customer charge of $28.00/month in roughly two years. Of course, the solar panel, the single most costly portion of this system would last for at least 20 years. If one assumes a 5-year lifetime for the battery and charge controller, the 20-year cost would still only be $6.34/month. Again, these numbers are conservative because the on-site system is overbuilt relative to the actual electricity service need. Regardless, no reasonable customer would pay DEC's proposed basic facilities charge, or even the current basic facilities charge, if they only wished to serve a minimal load. The Company's hypothetical minimum system would never be built under these circumstances.

[23] The customer would also avoid having to a small energy charge, roughly $0.25/month if one assumes the same light bulb operation and an energy rate of $0.05/kWh.

Q. IS THE MINIMUM SYSTEM METHOD GENERALLY ACCEPTED AS AN APPROPRIATE METHOD FOR CLASSIFYING DISTRIBUTION SYSTEM COSTS?

A. No. The Minimum System Method is based on the dubious premise that customers will pay to connect to the distribution grid even if they do not intend to use any electricity. In reality, a customer that has no demand for electricity would have no need to be connected to the distribution system. Distribution costs are caused by that demand and the customer density of a service territory, not by the presence of the customer. A zero- or minimum-demand customer of the type represented by the Minimum System Study or the Zero-Intercept variant simply does not exist.

Taken to its furthest extent, the flawed premise underlying the Minimum System Method effectively assumes that any distribution cost not proven to fall into another category must be customer-related. Dr. James Bonbright discusses this line of thinking in his seminal work *Principles in Public Utility Rates*. Dr. Bonbright acknowledges that one could devise a so-called minimum system, but dismisses the notion that the costs of that system are customer-related, referring to them as "unallocable".

> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of custômers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). *Indeed, if the company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system…*

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs... while it is also denied a place among the customer costs...to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs...But fully-distributed cost analyst dare not avail himself of this solution, since they are prisoners of his own assumption that "the sum of the parts is equal to the whole." *He is therefore under impelling pressure to fudge his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of their other cost categories.* [24] [emphasis added]

Q. WHAT ARE THE IMPLICATONS OF THE HYPOTHETICAL MINIMUM SYSTEM HAVING THE ABILITY TO SUPPORT NON-ZERO CUSTOMER LOADS?

A. It causes demand to be double-counted. A given class receives an allocation based on the minimum system on a per-customer basis, but because that minimum system has some level of load carrying capability, it contains demand-related costs. That same class is then allocated the remaining distribution costs based on their full demands. This tends to have disproportionately large impacts on residential classes because those classes typically have the largest number of customers, and are allocated comparatively more of the costs the Minimum System Method classifies as customer-related.

In light of this criticism, an alternative method typically referred to as the Zero-Intercept or Minimum Intercept Method has sometimes been used to classify distribution system costs as customer- or demand-related. The Zero-Intercept

[24] Dr. James Bonbright, *Principles of Public Utility Rates*, p. 348-349, Columbia University Press (1961).

Method uses statistical regression techniques to define the relationship between cost and load-serving capability. The result is a curve where equipment costs sit on one axis and load-serving capability sits on the other. Following the curve to the point where load-serving capability is zero (*i.e.*, the zero-intercept) produces an implied cost for equipment that is not capable of supporting any load.

Q. HAS THE COMPANY PERFORMED A ZERO-INTERCEPT ANALYSIS?

A. No. Company Witness Hager states that it has not done so because the analysis is more complex and often does not produce results much different than the Minimum System Method.[25] I find this explanation strange and unconvincing because the Company is clearly capable of performing complex analyses, such as a cost of service study or an integrated resource plan, and it is not possible to know whether such an analysis would produce results similar to the Minimum System Method unless one actually performs the study.

Q. DO OTHER STATES USE THE MINIMUM DISTRIBUTION SYSTEM METHOD FOR SETTING CUSTOMER CHARGES?

A. Many states confine the definition of "customer" costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the NARUC found that this "Basic Customer Method" (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report:

[25] Hager Direct. p. 14, lines 6-9.

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[26]

In other states, some portion of the shared distribution system may be considered customer-related and allocated on that basis, but the methodology used can vary from state to state.

Rate design practices are likewise variable because rate design involves a balance of numerous competing objectives, such as fairness, stability, effectiveness at meeting revenue requirements, cost causation, and customer acceptance. The balancing reflects the fact that these objectives are frequently in conflict with one another. As I showed in Section II-A of my testimony, regulators have *never* adopted residential fixed charges at the level proposed by the Company.

Q. IS THE MINIMUM SYSTEM METHOD ENDORSED BY NARUC FOR COST ALLOCATION OR RATE DESIGN PURPOSES?

A. No. First, the NARUC Cost Allocation Manual, as indicated by its title, addresses only cost allocation. It does not purport to address rate design based on the results of embedded cost studies. Second, the Cost Allocation Manual refers to the Minimum System Method as *one* method of classifying distribution costs, but it

[26] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, REGULATORY ASSISTANCE PROJECT (2000), *available at* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

does not endorse any method in particular. The preface expressly states this in the context of the objectives for the document, as follows:

> The writing style should be non-judgmental, not advocating any one particular method, but trying to include all currently used methods with pros and cons.[27]

The section on distribution cost allocation protocols goes on to note that the results are directly related to the assumptions used, such as how the minimum size distribution equipment is selected. Furthermore, the document includes statements advising readers of methodological concerns present with the Minimum System Method and highlighting that the issue of distribution cost classification is in no way settled, as follows:

> [M]inimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[28]
>
> The major issue in establishing the marginal cost of the distribution system is the determination of *what costs, if any, should be classified as customer related*, rather than demand and energy related. *The issue is a carry-over of the unresolved argument in embedded cost studies* with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.[29] [emphasis added]

Contrary to Company Witness Hager's statements, the Cost Allocation Manual does not affirm the Minimum System Method as the "right" way to allocate costs of the shared distribution system, or any method for that matter. Furthermore, it does not endorse the use of unit costs derived from cost allocation

[27] NARUC. Electric Utility Cost Allocation Manual. p. ii. 1991.
[28] *Id.* p. 95.
[29] *Id.* p 136.

studies for setting the rates for different types of charges, such as basic facilities charges.

Q. DO YOU SUPPORT THE USE OF A ZERO-INTERCEPT STUDY TO IDENTIFY CUSTOMER AND DEMAND-RELATED COMPONENTS OF THE SHARED DISTRIBUTION SYSTEM?

A. No. A Zero-Intercept analysis would be better than what the Company has put forth since it at least attempts to isolate and remove the demand component to avoid double-counting. However, it still fails to reflect the fact that a zero-load customer would have no need to be connected to the grid.

Q. WHAT APPROACH DO YOU THEN RECOMMEND THAT THE COMMISSION ADOPT FOR THE CONDUCT OF COST OF SERVICE STUDIES?

A. I recommend that the Commission use the Basic Customer Method because it more reliability avoids any double-counting of demand, is far simpler to execute, and is more broadly accepted as an appropriate mechanism. Furthermore, it reduces the downstream effects that classifying any portion of shared distribution system has on other dynamic allocators that derive in part from how distribution plant is classified. This avoids rendering the customer costs category "a dumping ground" for unallocable costs that Dr. Bonbright cautions against.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ON THE COMPANY'S MINIMUM SYSTEM STUDY AND THE ACCOMPANYING IMPACTS IT HAS ON THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. As I previously observed, the Minimum System Method tends to result in the more costs being allocated to the residential class because it defines more costs as customer-related and the residential class has more individual customers than other classes. Therefore, if class rates of return under present rates are evaluated, the residential class shows a lower rate of return than it would without a minimum system assumption. As shown in Pirro Exhibit No. 4, with the Minimum System Method incorporated into the Company's cost of service study, the return at present rates for the collective residential class is 3.82% while the system-wide return is 4.64%. This suggests that the residential class is underperforming relative to other classes (*i.e.*, being subsidized by other classes).

However, with the minimum system assumption removed, the residential class shows a return at present rates of 4.40%, only slightly less than the system-wide return at present rates. In addition, discarding the minimum system method generally reduces the class variance from the system average rate of return, meaning that all classes produce returns closer to the system average. Only the lighting class, the smallest rate class, shows an increase (a modest one) in terms of departure from the system average rate of return.[30]

This is significant because when evaluating the potential for inter-class subsidies, a no minimum system assumption provides a more accurate assessment

[30] DEC response to VS 1-8, attached in Exhibit JRB-2, p.6.

of class returns at present rates because it reflects the class return under the adopted cost allocation methods from which present rates are derived. Since the variance from the average rate of return under a no minimum system assumption is smaller than with a minimum system assumption, it follows that the no minimum system assumption is in fact better at accurately assigning class cost responsibility. With lower variances from average, less rate increase mitigation is required and the ultimate class returns after the rate increase and mitigation are clustered more closely around the system average rate of return. From a cost allocation standpoint, a no minimum system assumption produces more rational results.

C. An Appropriate Maximum Residential Customer Charge

Q. WHAT IS THE APPROPRIATE BASIS FOR SETTING RESIDENTIAL CUSTOMER CHARGES?

A. The customer charge should reflect the cost of a customer that does not impose a demand or consume energy. This cost is represented by the incremental cost of connecting a customer (*i.e.*, the marginal cost), which is generally limited to the costs for a meter and service drop along with expenses for meter reading, billing, and customer service.[31] Another way to view the appropriate role of the customer charge that typically produces a similar result is to define customer-related costs

[31] Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, at 36, REGULATORY ASSISTANCE PROJECT (July 2015), http://www.raponline.org/document/download/id/7680.

as those that vary directly with the number of customers.[32] However, it is a mistake to conflate the costs associated with such a zero-load customer with costs that are not directly correlated with customer demand or energy consumption. Many joint system costs vary more indirectly with one or more cost categories and consequently do not fall neatly within the customer, demand, or energy classification.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST OF SERVICE STUDY, WHAT WOULD BE A REASONABLE MAXIMUM RESIDENTIAL CUSTOMER CHARGE?

A. The Company's cost of service study shows that if the minimum system method is removed, the residential customer charge based on the customer unit cost is $15.86/month.[33] I have calculated a reasonable *maximum* residential customer charge of $11.64/month, based on eliminating the use of the Minimum System Method and then excluding a series of other cost components that do not relate to metering, billing, customer service, or the customer's connection to the shared distribution grid. I emphasize that this as a reasonable *maximum* charge because the Commission should also consider other ratemaking principles, such as gradualism, when determining the appropriate charge.

My derivation is largely reflective of how the Connecticut Public Utilities Regulatory Authority ("PURA") determined the appropriate costs includable

[32] *Id.* at 83.

[33] This translates to $16.01/month after adjusting for differences in how the Company counts customers for deriving the customer charge versus the customer counts used in the cost of service study.

within a Maximum Residential Customer Charge ("MRCC) in response to 2015 legislation limiting residential customer charges to costs directly associated with billing, metering, customer service, and the customer's service connection. The PURA conducted a year-long proceeding to develop a clear and consistent methodology, culminating in the issuance of a decision in December 2017 and subsequent revisions to utility charges. I believe the PURA's determinations represent a thorough, well-reasoned, and readily understandable evaluation of the costs directly attributable to metering, billing, customer service, and the customer's service connection.[34] [35]

Q. WHAT COST COMPONENTS HAVE YOU EXCLUDED FROM THE CALCULATION OF THE MAXIMUM RESIDENTIAL CUSTOMER CHARGE IN ARRIVING AT THE $11.64/MONTH FIGURE?

A. The costs I have excluded, and the reasons I excluded them are as follows:

1. AMI Amortized O&M: AMI serves energy- and demand-related functions far beyond the simple measurement of customer consumption for billing purposes, and the customer charge already includes the cost of non-AMI metering via recovery of the un-depreciated costs of those meters.

[34] Connecticut Office of Legislative Research. *Maximum Residential Customer Charge Research Report.*. June 12, 2018, *available at*: https://www.cga.ct.gov/2018/rpt/pdf/2018-R-0151.pdf.
[35] PURA Docket No. 17-01-12. Final Decision dated December 20, 2017, *available at*: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/484ed9e80c8e0044852581fc0070a1f6?OpenDocument.

2. Overhead Line Maintenance (FERC Account 593): Overhead lines are primarily part of the shared distribution system, not connecting the customer to that system, or serving billing, metering, or customer service functions.[36]

3. Uncollectable Accounts (FERC Account 904): Uncollectables are a general cost of doing business that have no relationship to the customer's connection to the grid. Any direct labor associated with collection activities would be contained in FERC Account 903, which I have not excluded.

4. Sales and Advertising Expenses (FERC Accounts 911-917): These accounts relate to activities such as the promotion of the sale of electricity, customer retention, and other work for sales purposes. While they may appear to be superficially related to customer service, direct customer service and assistance is logged in other accounts that I have not excluded.[37]

5. Miscellaneous Distribution Expenses (FERC Account 588): This account is a catch-all for costs that cannot be directly attributed to a more specific purpose. If these costs were truly customer-related they would be included in other applicable accounts (*e.g.*, metering expenses).

6. Load Dispatch (FERC Account 581): Load dispatch relates to activities associated with operation of the shared distribution system, such as voltage

[36] This account may include expenses associated with customer service drops, but it is not possible to separate these out based on the information I have access to. The PURA allows this account to be included in the MRCC calculation, but directs that utilities exclude all costs not associated with the customer's service connection.

[37] FERC Account 909 is also associated with miscellaneous informational, instructional, and advertising expenses and therefore merits exclusion as well. However, the Company's cost of service study groups FERC Accounts 906-910 together so it is not possible to separate includable costs in the other accounts from those associated with FERC Account 909.

control and switching. It does not relate to the customer connection, metering, billing, or customer service.

7. Distribution Pole Rental Revenues (FERC Account 454): This account represents an additional charge in my calculations, since it assigns additional revenue that offsets costs to the customer-related category. In order to maintain consistency with excluding shared system costs from the customer charge, additional revenues that relate to the shared system should be excluded as well.

8. Carolinas West Control Center Depreciation and Amortization: These costs relate to the general operation and management of the electric grid, not customer connections, metering, billing or customer service.

9. Grid Improvement Plan Depreciation and Amortization: As I discuss in more detail in Section V of my testimony, the Grid Improvement Plan does not feature investments associated with customer connections, metering, billing or customer service.

Q. DID YOU EXCLUDE ANY GENERAL PLANT OR GENERAL ADMINISTRATIVE EXPENSES IN YOUR CALCULATION OF AN APPROPRIATE MAXIMUM RESIDENTIAL CUSTOMER CHARGE?

A. I made no exclusions beyond those described above, though it may be appropriate to do so. The Company's cost of service study allocates administrative and general expenses (FERC Accounts 920 – 931) and plant (FERC Accounts 389 – 399) based on a Labor allocator or other generalized allocators (*e.g.*, total net plant in service, distribution plant). These plant accounts pertain to assets like office furniture, tools, transportation and communications equipment, while the expense accounts relate to things like salaries not charged to another account, office supplies, insurance, and employee pensions.

The Connecticut PURA allows the plant accounts to be included in the calculation of MRCC, but has directed utilities to use a direct assignment methodology (*i.e.*, an examination at the individual asset level) to determine the portions of plant related to the applicable statutory functions. With respect to expenses, it permits the inclusion of property insurance, injuries and damage, and employee pensions and benefits in the MRCC calculation without requiring direct assignment, but requires direct assignment for expenses associated with non-specific salaries (FERC Account 920), office supplies (FERC Account 921), and consultant services (FERC Account 923) with a rebuttable presumption that these costs are not includable in the MRCC. It excludes the remaining administrative and general expenses entirely.

I have not made any adjustments to these costs in my calculation because I have no way to discern appropriate direct assignments, and the version of Company's cost of service study that I have access to groups plant and expenses into broad categories (*i.e.*, FERC Accounts 920-931) rather than displaying components at the individual FERC Account level.[38]

[38] The PURA also excluded FERC Account 371 relating to installations on the customer premises on the customer side of the electric meter under the rationale that such costs should be addressed by direct assignment. The Company includes a small amount of plan in this account for customers on Schedule RE.

Q. WHY IS DIRECT ASSIGNMENT IMPORTANT WHEN IT COMES TO THE PROPER ASSIGNMENT OF ADMINISTRATIVE AND GENERAL COSTS?

A. Administrative and general costs are highly diverse and many categories bear no relationship to the costs associated with connecting a customer to the grid. For instance, executive compensation and aviation expenses are logged as general costs and allocated using a Labor allocator in the Company's cost of service study. The use of the Labor allocator results in a portion of these costs being classified as customer related. The exact amount depends on the class and cost of service study assumptions, but under the Company's minimum system cost of service study, for the RS class the Labor allocator logs 22.5% of these costs as customer-related. Under a no minimum system cost of service approach, the percentage is lower at 15.8%.[39]

These amounts are often small individually, but they add up, and regardless of their individual size it is inappropriate for them to be considered customer-related components that contribute to the basic facilities charge. This downstream effect also highlights the less easily observable impacts of utilizing the Minimum System Method for cost allocation or as an input to rate design. To wit, the use of the Minimum System Method invariably causes greater amounts of costs that have no discernable relationship to the number of customers a utility serves to be classified as customer-related.

[39] See DEC responses to VS 1-20 depicting pro forma adjustments to administrative and general expenses under a minimum system assumption and separately under a no minimum system assumption, Exhibit JRB-2, p. 10.

Q. YOU PREVIOUSLY STATED THAT COSTS THAT VARY DIRECTLY WITH THE NUMBER OF CUSTOMERS ARE REASONABLE TO INCLUDE IN THE CUSTOMER CHARGE. PLEASE THEN EXPLAIN MORE DETAIL WHY YOU EXCLUDED AMI COSTS IN YOUR CALCULATION.

A. While it is true that metering and associated metering costs are typically recovered through fixed monthly charges, AMI is not "typical" metering. As I previously stated, fixed customer charges should recover the cost of connecting a customer to the grid. Advanced metering and the associated incremental costs above traditional meters are not strictly necessary for the customer to be connected to the grid. A non-advanced meter and associated infrastructure can do so at lower costs. AMI is used for much more than measurement of a customer's consumption for billing purposes. Furthermore, since customers do not have a meaningful choice of whether to take service through an advanced meter from a cost perspective, those customers are not truly "causing" the incremental advanced metering costs. Treating AMI costs exclusively as customer-related just because they relate to "metering" and consequently recovering them through a fixed charge is an oversimplification of the cost causation factors at play.

Q. SHOULD THE COMMISSION ATTRIBUTE THE COSTS OF AMI AS RELATED PRIMARILY TO PRODUCING ENERGY AND PEAK DEMAND SAVINGS?

Yes. The incremental costs of AMI above traditional metering are more accurately viewed as primarily energy- and/or demand-related because AMI deployment is generally undertaken with a goal of producing system cost savings associated at least in part with energy- or demand-related functions, or system operation and reliability. Furthermore, including these costs as a component of a fixed monthly charge works at cross-purposes with the goal of enabling greater customer control over their energy bills. Finally, it is fundamentally unfair to require customers to effectively pay two fixed metering charges at the same time, one for the un-depreciated cost of legacy meters and one for AMI infrastructure and associated O&M costs.

Q. ARE NOT CUSTOMERS CURRENTLY BENEFITTING FROM AMI DEPLOYMENT?

A. They are according to Company estimates, but not in amounts commensurate with the costs. The annual revenue requirement associated with the Company's proposal to amortize deferred AMI costs is $15 million.[40] Company Witness Schneider estimates that during 2017, it avoided costs of $540,000 via remote order fulfillment capability and $524,000 via remote meter reading capability made possible by AMI.[41]

Q. ARE THE COMPANY'S STATED JUSTIFICATIONS FOR AMI DEPLOYMENT CONSISTENT WITH THE GOAL OF PRODUCING ENERGY AND DEMAND COST SAVINGS?

A. Unfortunately, the Company's plans in this area lack specificity and to my knowledge the Company has not conducted a cost-benefit analysis of AMI

[40] Direct Testimony of Kim H. Smith ("Smith Direct"), p. 24, line 19.
[41] Direct Testimony of Donald Schneider ("Schneider Direct"), p. 10, line 20 through p. 21 line 4.

deployment in South Carolina. Company Witnesses Hunsicker and Pirro obliquely reference AMI, coupled with the new Customer Connect billing system, as enabling its ability to offer more advanced rate designs in the future. For instance, Company Witness Hunsicker states "As referenced in Witness Pirro's testimony, the deployment of Customer Connect combined with the nearly complete installation of AMI meters across the Company's service territory will unlock the tools required to bill innovative rate designs using interval level data to customers."[42] Company Witness Pirro notes that while the Company has not proposed any new peak or real-time pricing designs, it continues to review "rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service."[43]

Nevertheless, the AMI cost-benefit analysis the Company was ordered to conduct in North Carolina provides useful information on this topic, showing that expected AMI benefits to customers are dominated by benefits unrelated to customer-specific costs. Roughly 28% of the estimated long-term benefits display a clear connection to the customer classification, composed of reduced metering reading costs, reduced meter operations costs (including remote connection and disconnection), and reduced failure of legacy meters. The remaining benefits are associated with outage restoration O&M, "miscellaneous" O&M, capital cost

[42] Direct Testimony of Retha Hunsicker ("Hunsicker Direct"), p. 12, lines 8-12.
[43] Pirro Direct, p. 11, lines 6-8.

savings such as distribution loading analysis and improved capacitor bank placement, and "non-technical line loss reduction".[44]

Non-technical line loss reduction provides the single largest estimated benefit, totaling roughly 63% of total estimated benefits.[45] This category of benefit refers to additional revenue capture from a reduction in instances of meter non-performance, power theft, equipment errors, and misconfiguration.[46] Such revenue erosion is a generalized cost of doing business without any clear tie to customer-related utility functions somewhat akin to uncollectable accounts. When decisions about the merits of AMI deployment are based on future customer benefits of this type, the cost of AMI is properly attributable to achieving those benefits.

Furthermore, while the Company has not provided any analysis of potential energy and demand savings enabled by AMI via advanced rate designs, it is generally accepted and recognized that such future savings are one of the primary reasons for AMI deployment. As I discuss in more detail later in my testimony, North Carolina regulators have expressly emphasized peak demand and energy savings as a key benefit of AMI deployment. I encourage the Commission to do so here as well, both from the perspective of the rate design for

[44] NCUC. Docket No. E-100, Sub 147. 2017 Smart Grid Technologies Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC. October 2, 2017. Appendix C, Exhibit C. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=21f06c4c-f377-4425-a865-65b777e6a18b

[45] *Id.*

[46] *Id.* Appendix C, Exhibit F.

AMI cost recovery and the need for prompt development of innovative rate designs that make these savings possible.

Q. ARE YOU SUGGESTING THAT AMI COSTS BE ALLOCATED IN A MANNER OTHER THAN ON A PER CUSTOMER BASIS?

A. No. AMI costs vary directly with the number of meters that must be installed. Therefore, it is reasonable to allocate these costs based on the number of customers. The residential class requires more meters therefore it should bear an equivalent portion of the costs. However, rate design should reflect the fact that the costs are not attributable to the decisions of individual customers, and that the incremental costs of AMI are related primarily, if not exclusively, to long-term energy and demand cost savings for individual ratepayers and the system as a whole.

Q. GIVEN THAT AMI AND THE COMPANY'S CUSTOMER CONNECT SYSTEM ARE PART OF AN INTEGRATED PLATFORM, HAVE YOU MADE ANY ADJUSTMENTS TO HOW THE COSTS OF CUSTOMER CONNECT ARE APPROPRIATE TO REFLECT IN RATE DESIGN?

A. No, but such an adjustment could be reasonable. The Customer Connect system is an integral element to realizing the full value of AMI (and its associated benefits) and is designed to possess capabilities far beyond those necessary for simple billing purposes. It follows that a portion of Customer Connect costs likewise have an energy- and demand-related purpose. If 50% of Customer Connect expenses related to O&M and depreciation and amortization were removed from the customer-related classification, my calculation of a maximum reasonable basic facilities charge would be reduced by $0.34/month to $11.30/month.

Q. AT WHAT AMOUNT DO YOU RECOMMEND THE COMMISSION SET THE RESIDENTIAL BASIC FACILITIES CHARGE?

A. I recommend that the residential basic facilities charge be increased by no more than the percentage revenue increase the Commission adopts for the residential class. Under the Company's proposed cost of service study, including the use of the Minimum System Method, this would result in an increase of $1.45/month to $9.74/month. Removing the Minimum System Method produces a slightly lower residential revenue increase and percentage increase, which would lead to a $1.33/month increase in the basic facilities charge to $9.62/month. This method strikes a reasonable balance between cost-based pricing and gradualism, especially considering the partially energy- and demand-related aspects of Customer Connect, and the fact that a detailed examination of general and administrative costs was not possible.

It also produces a result that is similar to what the Company proposed in North Carolina based on my derivation of maximum cost-based pricing. The increases shown above would move customers roughly 40% of the way towards the maximum charge of $11.64/month that I have derived. The increase would also be slightly above national averages, but not dramatically so, partly due to the fact that DEC's current charge is moderately below the national average. Overall, this strikes a reasonable balance between competing ratemaking objectives.

III. SOLAR BENEFITS IN COST OF SERVICE

Q. PLEASE EXPLAIN IN GENERAL HOW ON-SITE SOLAR GENERATION AFFECTS AN EMBEDDED COST OF SERVICE STUDY?

A. On-site solar generation helps avoid both current and future costs. I focus here on how on-site solar affects the allocation of costs in the Company's embedded cost of service study. In this frame, on-site solar generation reduces and shifts load placed on the generation, transmission, and distribution system by way of reductions in customer loads and exports to the grid. This load reduction and shifting translates to changes in both jurisdictional and South Carolina retail class allocations. That is, when on-site solar generation reduces load in South Carolina at the time of the Company's summer coincident peak, South Carolina customers are allocated fewer costs for utility functions for which allocators are based on contribution to the system peak (*i.e.*, production demand and transmission). The same effect occurs at the retail customer class level.

A similar effect can occur at the distribution level, for which costs are allocated based on non-coincident class peak demand. While solar does not generally reduce the non-coincident peaks of individual customers, it can do so at the customer class level if the timing of the class peak coincides with a time period where solar production is occurring. By reducing class demand at that hour, solar may equivalently reduce the class peak to a lower amount, or may cause the class peak hour to shift to another hour with a lower class peak (*i.e.*, the reduction may not have a 1:1 relationship to generation).

Q. CAN THE IMPACTS OF THESE AFFECTS BE QUANTIFIED?

A. Yes. I have estimated that residential net-metered solar production at the time of the Company's test year coincident peak can be expected to have reduced production demand and transmission demand costs allocated to the residential customer class by roughly $1.08 million dollars. This amount is composed of roughly $249,000 representing the residential class's share of jurisdictional cost savings and roughly $827,000 representing South Carolina retail allocation savings. Other classes benefitted from the remaining jurisdictional cost savings of roughly $395,000.

Q. PLEASE EXPLAIN HOW YOU MADE THESE CALCULATIONS.

A. I first developed an estimate for what residential solar production would have been at the time of the retail system peak, the hour ending at 3 PM on August 17, 2017. For my estimate, I used PVWatts to develop an average solar capacity factor for the hour ending at 3 PM during the month of August. This is reflective of a "typical meteorological year" as used by PVWatts. I applied this to data provided by the Company showing that as of the date of the peak, it had roughly 26.3 MW-DC of residential solar net-metered capacity on the system.[47] I also grossed up the expected solar capacity contribution for marginal capacity losses.

I then used this capacity contribution to calculate revised production cost allocators that reflect a no residential solar assumption. To do this I added the solar capacity contribution to applicable system-wide, South Carolina, and

[47] DEC response to VS 4-11(b), attached in Exhibit JRB-2, p.16. This response states that this figure is for July 31, 2018, but, per confirmation of DEC counsel, the correct date is July 31, 2017.

residential class peaks. These alternates produce higher percentage allocators to South Carolina and the South Carolina residential customer class. For instance, the residential class percentage of the system peak is roughly 0.23% higher under a no residential solar scenario. Applying the percentage differences to the sum of production demand and transmission demand revenues produces the monetary benefits.

Q. DOES THIS REFLECT THE FULL RANGE OF BENEFITS PRODUCED BY NET METERED SOLAR SYSTEMS TODAY?

A. No. It only reflects residential systems that existed at the time of the test year peak, excluding all non-residential systems and residential systems installed since then. The savings will grow over time, though they will not be realized until the results of a new cost of service study are reflected in rates. The savings amounts that I have estimated will persist until a new cost of service study is conducted and reflected in rates as an annual benefit because they are based on annual revenue amounts.

In addition, the savings amounts do not reflect potential residential class benefits from reductions in non-coincident class peak due to direct reductions or shifting. The data necessary to conduct an examination of this potential source of savings is not available. They also do not reflect the incremental value of net metered energy generation, as reflected in difference between the marginal time differentiated value of net metered generation and the base energy rate.

Q. WHAT IS THE SIGNIFICANCE OF THE SAVINGS DATA YOU HAVE PRESENTED HERE?

A. Beyond contributing to long-term cost savings based on avoided future costs, residential net-metered solar is currently producing recurring, tangible cost savings for the residential class and for South Carolina retail customers as a whole.

IV. DEPLOYMENT OF INNOVATIVE RATE DESIGNS

Q. HAS THE COMPANY DEVELOPED ANY CLEAR PLANS FOR DEVELOPING AND DEPLOYING INNOVATIVE OR ADVANCED RATE DESIGNS?

A. No. As I mentioned previously, Company Witnesses Hunsicker and Pirro make vague references to AMI-enabled rate designs in their testimony, but do not articulate any specifics in terms of the timing or character of future offerings. Company Witness Hunsicker notes that Customer Connect Platform, which is an important element of implementing new rate designs, will not be fully deployed until 2022.[48]

[48] Hunsicker Direct. p. 12, line 22.

Q. WOULD IT BE REASONABLE FOR THE COMPANY TO DEFER DEVELOPING INNOVATIVE RATE DESIGN OPTIONS UNTIL AMI AND THE CUSTOMER CONNECT SYSTEM IS FULLY OPERATIONAL?

A. No, for several reasons. First, developing new rate designs that respond to both customer preferences and produce system savings is not a quick process. It takes time to design new rates for deployment on a pilot basis, more time (a year or more) to conduct the pilots, time to evaluate the results, and more time to come up with permanent rate options. It would not be unusual for such an effort to extend over several years since the process must generally proceed in a step-wise fashion.

Ideally, rate pilots, or at least the planning activities for pilots, are conducted in advance of full deployment or concurrently while deployment is taking place. It is not unusual for regulators to require rate pilot plans as part of applications seeking approval to deploy AMI, or to condition approval of AMI deployment on the prompt commencement of planning and rate pilot development. The rationale for this type of progression is that since customers are paying for AMI deployment (or presumably will be at the conclusion of this rate case for DEC), they should be provided with opportunities to take advantage of AMI capabilities as early as possible. This in part reflects a standard of ratemaking that conditions cost recovery on investments being used and useful. Persistent under-utilization calls the reasonableness of cost recovery into question.

Second, in order to ensure that the overall integrated system is capable of supporting the rate designs and features that customers desire, it is important to generate intelligence on those preferences as early as possible. It is tempting to view AMI and modern customer information systems as uniform monoliths that will ultimately be capable of meeting virtually any need. However, constructing an integrated system is a complex affair and decisions about architecture early on may have unanticipated consequences in the longer term. In other words, it is better to know as much as possible as early as possible in order to ensure that the design is consistent with the features that customers need and desire.

Third, there is little reason to not begin generating information as early as possible. There is no scenario where developing a suite of new rate options should not involve the conducting pilots to gauge customer preferences and evaluate results. Any costs associated with such an exercise will have to be incurred sooner or later. While it is possible that some costs, such as a need to perform manual billing, might be lessened or eliminated by waiting, waiting has a cost as well in the form of potentially years of foregone savings enabled by AMI.

Q. YOU PREVIOUSLY MENTIONED THAT THE COMPANY IS PARTICIPATING IN A RATE DESIGN STUDY WITH EPRI. HOW SHOULD THAT IMPACT THE DEVELOPMENT OF NEW RATE DESIGNS?

A. I expect that the EPRI study contains valuable information and I would expect it to inform the Company's plans. Now would be the perfect time to put the results into tangible practice via rate pilots. To be clear, the precise details of the study are not known to me, but it is hard to see circumstances where the EPRI study could be a substitute for actual on the ground information specific to DEC's customers. In addition, since the study and its results are not publicly accessible, there is a need for transparent evaluations conducted in full view of stakeholders and the Commission.

Q. IS THE COMPANY PURSUING ADVANCED RATE PILOTS IN OTHER JURISDICTIONS?

A. Yes. At the conclusion of DEC's most recent North Carolina general rate case, the NCUC ordered it to "design and propose new rate structures to capture the full benefits of AMI".[49] The Order further required DEC to file the details of proposed dynamic rate structures within six months, in order to "allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy."[50] DEC filed a report in compliance with this Order in December 2018, but NCUC found the report non-compliant with its prior decision because among other things, the report did not contain any details of new tariffs, and the Company's proposed timeline (March 2022) for finalizing new rate designs was too long.[51]

In declining to accept the filing, the NCUC observed that this date would be almost three years after the full completion of AMI deployment, and that DEC

[49] NCUC. Docket No. E-7, Sub 1146. Order dated June 22, 2018. Finding of Fact No. 39, *available at:* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.
[50] *Id.* p. 124.
[51] NCUC. Docket No. E-7, Sub 1146. Order dated January 30, 2019. p. 4, *available at:* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=12af76f3-f507-4352-92ec-32facb7eaba0.

should already possess a large amount of information about AMI capabilities and customer usage profiles.[52] Ultimately, the NCUC directed the Company to file revised rate design pilot program plans and two specific rate design pilots within 60 days. One rate pilot must be applicable to residential service and one to small general service customers. A hearing on the progress DEC has made is scheduled for February 26th and the new compliance filing is due on or around April 1st.[53]

Q. GIVEN THESE CIRCUMSTANCES, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING ADVANCED RATE DESIGN DEPLOYMENT IN SOUTH CAROLINA?

A. The Commission should direct DEC to make compliance filings at least equivalent to those that the NCUC has required within 60 days, composed of a detailed advanced rate design deployment plan and two specific pilot rate proposals. Such a timeline is short, but not unreasonable because the North Carolina filings will already have been completed by the time the Commission issues a decision in this proceeding. DEC will already have a roadmap from which to work. I also strongly encourage the Commission to seek to align future timelines with those established in North Carolina given the integrated nature of DEC's North Carolina and South Carolina divisions. An integrated approach for AMI-enabled rate design would be more efficient than separate, disconnected efforts.

[52] *Id.* p. 4-5.
[53] *Id.* p. 4 and p. 6.

V. GRID IMPROVEMENT PLAN COST ALLOCATION AND RATE DESIGN

Q. PLEASE BRIEFLY SUMMARIZE THE NATURE OF INVESTMENTS DEC SEEKS TO UNDERTAKE AS PART OF ITS GRID IMPROVEMENT PLAN.

A. Broadly speaking, the Grid Improvement Plan investments are a collection of transmission and distribution system investments targeted at addressing "Megatrends" impacting grid operations, incremental to the work the Company performs "to maintain base-level operations."[54]

Q. HOW DOES DEC PROPOSE TO RECOVER THE COSTS OF MAKING THESE INVESTMENTS?

A. The Company proposes to establish a special Grid Improvement Plan tariff rider for two phases of the plan, where Phase 1 begins June 1, 2020 and Phase 2 begins June 1, 2021 with incrementally higher charges than for Phase 1. The rates in the proposed tariff are composed of an incremental monthly fixed charge and an incremental volumetric charge. For the residential class the proposed charges are as follows:

- Phase 1: $0.42/month and $0.1124/kWh
- Phase 2: $0.59/month and $0.1332/kWh[55]

Q. HOW ARE THESE CHARGES DERIVED?

A. The derivation of the class allocators and the rates themselves stem from the Company's cost of service study, inclusive of the effects of the Minimum System

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[54] Direct Testimony of Jay Oliver ("Oliver Direct"), p. 28, lines 3-5.
[55] Pirro Direct, Exhibit No. 7.

Method of assigning costs associated with the shared distribution system. The revenue for the fixed charge portion is based on the percentage of distribution plant classified as customer-related in the cost of service study. This has two effects. First, because most investments are distribution-related, the residential class is allocated a disproportionate share of the costs, 61.6% for Phase 1 and 61.8% for Phase 2. Second, the charges for the residential class are weighted far more heavily towards the fixed monthly charge component than they are for other classes composed of customers with higher loads. For residential customers the fixed component comprises 22.7% of total revenue for Phase 1 and 29.4% for Phase 2. By comparison, for Phase 1 the fixed component for the large general service class comprises only 2.2% of the revenue requirement.[56]

Q. WHAT ARE YOUR GENERAL CONCERNS ABOUT THE COMPANY'S GRID IMPROVEMENT PLAN?

A. My first concern is that while the residential class would pay for most of the costs associated with the plan, it is not clear that it would receive an equivalent share of the benefits. Given the significance of the cost burden on residential customers it is only reasonable that the Company identify at a granular project or asset-based level to whom the benefits will accrue. I have seen no analysis of this variety in the materials the Company has provided in its application and in response to information requests.

My second concern is how the proposed rate design is affected by the Company's use of the Minimum System Method in its cost of service study. As I

[56] Calculations based on Pirro Direct, Exhibit No. 7.

have previously discussed at length, the Minimum System Method is not a valid or accurate method for cost allocation or rate design and should be disregarded by the Commission. Furthermore, since the investments and costs associated with the Grid Improvement Plan are characterized as incremental to "base-level operations" it is difficult to grasp how they could be considered integral and included within a so-called minimum system. Investments and costs beyond the normal course of business are by their very nature not investments in a minimally capable system and I have not identified any Grid Improvement Plan costs that are truly customer-related in nature.

Q. BEYOND THE APPLICABILITY OF THE MINIMUM SYSTEM METHOD TO ANY GRID IMPROVEMENT PLAN COSTS, DO YOU HAVE ANY OTHER CONCERNS ABOUT THE COMPANY'S PROPOSED RATE DESIGN?

A. Yes. The Company's derivation of the customer-related percentage of distribution costs is incorrect. As I previously noted, that percentage is calculated using the percentage of total distribution plant that is classified as customer-related in the Company's cost of service study. For Schedule RS customers, that amount of 59.46%, resulting in 59.46% of Grid Improvement Plan distribution investments being classified as customer-related and therefore recoverable via the fixed monthly charge.

This calculation is erroneous because the 59.46% figure includes costs associated with meters and service drops while none of the Grid Improvement Plan investments relate to these types of equipment. Even if one accepts the

Minimum System Method as valid for use in rate design for the Grid Improvement Plan, including meter and service drop costs in calculating the customer-related percentage is in error. A correct calculation removes these costs from both the numerator and denominator. For the RS class, that reduces the customer-related portion from the Company's 59.46% to the correct amount of 48.95%, the class percentage of customer-related distribution costs excluding costs with no relation to Grid Improvement Plan investments.

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE TO ADDRESS THESE CONCERNS?

A. I recommend that the Commission take several actions to the extent that allows the Company to move forward on any aspects of the Grid Improvement Plan, as follows:

1. Direct DEC to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align the allocation of costs for the Grid Improvement Plan with the results of the class-level cost-benefit evaluations.
2. Make a finding that no Grid Improvement Plan costs can be considered to be costs associated with a minimum distribution system, even if the Commission allows the use of the Minimum System Method for other purposes.
3. Direct DEC to perform a granular examination of the costs of any Grid Improvement Plan projects that move forward to identify what portion of those costs are energy- and demand-related.

4. Direct that the rate structure for recovery of any costs associated with the Grid Improvement Plan be aligned with how those costs would be recovered according to their energy- or demand-related characteristics.
5. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

VI. RATE STRUCTURE FOR RIDER EDIT-1

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RIDER EDIT-1 AND ITS PURPOSE.

A. Rider EDIT-1 is a mechanism for refunding to customers the excess money that the Company has collected for net deferred tax liabilities, stemming primarily to a change in federal corporate income tax rate from 35 percent to 21 percent. The rates in Rider EDIT-1 reflect a simple division of the excess revenue by class divided by test year sales.[57] Thus the proposed rate, a credit, is a volumetric price in cents/kWh.

Q. HOW DOES THE COMPANY JUSTIFY THE VOLUMETRIC STRUCTURE FOR RIDER EDIT-1?

A. The Company's justification for the volumetric rate structure is not spelled out in testimony. However, in response to an information request, DEC stated that the

[57] Pirro Direct, Exhibit No. 8.

volumetric design was selected for administrative simplicity and because energy determinants are more predictable than demand determinants.[58]

Q. PLEASE DESCRIBE EXCESS DEFERRED INCOME TAXES AND HOW THEY HAVE ARISEN FOR DEC?

A. Company Witness Panizza discusses the conceptual framework of deferred income tax liabilities and how an "excess" has arisen in detail.[59] At a very high level though, accumulated deferred income tax liabilities, or assets, arise because of timing differences between when income taxes are collected in rates and when those taxes are actually paid. As Witness Panizza describes, any balances eventually converge to zero over the life of the underlying cause of the deferred balance.[60] However, a change in tax laws disrupts this eventual convergence because past assumptions of future tax liabilities are no longer accurate. Such is the case with a reduction in the federal corporate income tax rate from 35 percent to 21 percent. Company Witness Panizza states that the net deferred tax liability underlying the excess is "driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes.[61]

Q. HOW ARE ACCUMULATED DEFERRED INCOME TAXES ("ADIT") ADDRESSED IN THE COMPANY'S COST OF SERVICE STUDY?

A. The class allocation is based on net plant including nuclear fuel, consistent with the fact that ADIT associated almost exclusively with fixed assets. This results in

[58] DEC response to VS 2-5(a), attached in Exhibit JRB-2, p.12.
[59] Direct Testimony of John Panizza ("Panizza Direct"), p. 7-12
[60] *Id.* p. 9, lines 3-11.
[61] *Id.* p. 7, lines 10-11.

the majority being classified as demand-related (production, transmission, or distribution) and 13.6% classified as customer-related.[62] Only a very small amount, roughly 2.3%, is related to production energy. If the Minimum System Method of classifying distribution costs is eliminated, the customer-related component is 7.2%.[63]

Q. CONSIDERING THE ORIGINS OF ADIT AND THE COMPANY'S TREATMENT OF IT IN ITS COST OF SERVICE STUDY, IS A VOLUMETRIC RATE APPROPRIATE FOR RIDER EDIT-1?

A. No. The origins of the excess deferred income taxes giving rise to Rider EDIT-1 bear little relationship to energy-related functions.

Q. WHAT WOULD BE AN APPROPRIATE STRUCTURE FOR RIDER EDIT-1, TO THE EXTENT IT IS APPROVED BY THE COMMISSION?

A. A percentage of bill-based design would create a better tie between rates and the underlying cost structure and preserve the rate structure that the Commission ultimately adopts for base retail rates in the rider. In other words, the rate design that the Commission determines to be reasonable for base rates would automatically be reflected in bill credits to customers. Customers that pay a large portion of their rates in the form of demand charges would receive effective demand rate reductions while effective customer charges and energy charges would be modified in the same manner. This type of rate structure is no more

[62] DEC response to VS 1-20 Attachment 1. See Tab titled "Toretail" at line 711.
[63] DEC response to VS 1-20 Attachment 2. See Tab titled "Toretail" at line 695.

administratively complicated and no less predictable than a credit based on an energy-only bill determinant.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE TOPIC OF THE RESIDENTIAL BASIC FACILITIES CHARGE.

A. My recommendations on the establishment of the basic facilities charge are as follows:

1. The Commission should reject the changes the Company has made to its cost of service study and re-affirm precedent by directing the Company to eliminate the use of the Minimum System Method from its cost of service study.
2. The Commission should make a determination that the basic customer method, which defines customer-related costs as those directly attributable to a customer's service connection, metering, billing, and customer service, is the appropriate method for classifying customer-related costs.
3. The Commission should reject the Company's proposed residential basic facilities charge and instead limit any increase in the charge to the percentage increase in the residential class revenue requirement that is ultimately adopted in this proceeding.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON AMI-ENABLED RATES, THE GRID MODERNIZATION PLAN, AND RIDER EDIT-1.

A. My recommendations on these topics are as follows:

1. AMI-Enabled Rate Design: The Commission should direct DEC to proceed with rate pilots and planning in a manner that is fully aligned with the directives placed on DEC in North Carolina, including but not limited to filing two pilot rate proposals, one for residential customers and one for small non-residential customers, and a complete rate design plan with the Commission within 60 days of a decision in this proceeding.
2. Grid Modernization Plan: The Commission should take several actions to ensure that the costs and benefits of the Company's Grid Improvement Plan are distributed equitably and are consistent with cost causation:
    a. Make a finding that Grid Improvement Plan investments cannot be considered part of a standard minimum distribution system because by their very nature they are extraordinary in character, regardless of whether the Commission accepts the use of the Minimum System Method in the Company's cost of service study.
    b. If the Commission approves the Grid Improvement Plan and the Company's proposed allocation and rate design generally, direct the Company to revise the customer-related percentage calculation to fully exclude distribution plant associated with meters and service drops.

c. Direct DEC to perform cost-benefit evaluations that address the relative customer class distribution of costs and benefits at the project level, and align the allocation and recovery of costs with the results of the class-level cost-benefit evaluations and proper identification of energy and demand costs.

3. Rider EDIT-1: If the Commission approves Rider EDIT-1, the rate design should be revised to a percentage of bill-based mechanism in order to align it with the underlying causes of excess deferred income taxes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.